Final Report

Long-Range Planning – Phase 2

Great Lakes Utilities
Manitowoc, Wisconsin

Great Lakes Utilities

April 3, 2020

leidos

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Introduction

Rigorous power supply planning is essential in order to provide policy makers with guidance to economically develop the Great Lakes Utilities ("GLU") electric power supply portfolio to help ensure reliable, low-cost, and environmentally sound wholesale electric service to the GLU members.

GLU has retained Leidos Engineering ("Leidos") to review the long-range power supply planning ("LRP") developed by GLU.

GLU-East and GLU-West Members

GLU has two separate groups of members for power supply planning purposes: GLU-East and GLU-West.

GLU-East has the following participating power supply members:

- Badger Power Marketing Agency (City of Shawano Utilities and Clintonville Utilities)
- Kiel Electric Utility
- Manitowoc Public Utilities ("MPU") (load following up to 77 MW until termination of the MPU-GLU generation lease agreement at the end of 2026 and 13 MW after 2026)
- Wisconsin Rapids Water & Light
- Stratford Water & Electric (starting 2020)[1]

GLU-West has the following participating power supply members:

- Bangor Municipal Utilities
- Cornell Municipal Electric Utilities
- Medford Electric Utilities
- Trempealeau Municipal Electric Department

Study Approach

A separate study over the 20-year period 2019 to 2038 (the "Study Period") was prepared by GLU for each of the two groups and in addition, as part of the GLU-West study, an option that assumed a merger of GLU-East and GLU-West in conjunction with a common power supply program, was evaluated.

In preparing the GLU power supply planning study over the Study Period, GLU utilized a Monte Carlo simulation approach in modeling and assessing future power supply requirements, costs, conditions, and potential portfolios. As such, no selected sensitivity

[1] The Stratford electric load, which has an approximate peak of 3 MW, was not included in this study.

cases were explicitly studied, but rather, key input variables were allowed to randomly range over various distributions as described in more detail below. A population of 200 simulations were produced for each of the planning options for GLU-East and the planning options for GLU-West, which are described in more detail in Section 1.

In the preparation of this Report, including the results and findings contained herein, Leidos relied on data and information supplied by the client and others as well as certain assumptions and considerations with respect to conditions that may occur in the future. While these considerations and assumptions are reasonable based on information known as of the date of this study, future standards and system changes may alter the results and findings. In addition, field conditions encountered during any project development or design may impact some of the projects.

Leidos has relied on information and data provided by the client, including descriptions and summaries of the planning process and results as well as detailed historical and forecasted load for the GLU members and operating characteristics and costs of power supply resources. To the extent actual future load growth, operating characteristics and costs of power supply resources are different from those forecast for this study, the results and conclusions could and will likely change.

Contract Purchases and Terminations

All of the GLU-East and GLU-West planning options described below include the existing contract purchases and terminations as shown in Section 1.

Purchase of Short-term Peaking Capacity

All of the GLU-East and GLU-West planning options include the purchase of short-term peaking capacity to meet all capacity requirements not provided by owned, leased, or contracted capacity.

Purchase of MISO Energy

All of the GLU-East and GLU-West planning options include the purchase of energy from the MISO energy market to meet all energy requirements not provided by owned, leased, or contracted energy. [2]

Demand-Side Management and Emerging Technologies – GLU-East

All of the GLU-East planning options include demand-side management ("DSM") programs, which reduced capacity needs ranging from 1 MW in 2019 to 12 MW in 2023 and to 6 MW in 2038. The forecast included the following emerging technologies: electric vehicles, which increased the forecast of energy served by GLU, and rooftop photovoltaic solar, which decreased the forecast.

[2] All GLU energy is purchased from the MISO energy market, but the purchase of energy from the existing and proposed resources is simultaneously sold into the MISO energy market. There is a simultaneous purchase of energy from the MISO energy market at the same price as the sale into the MISO market for an equivalent amount of energy for the GLU load. These transactions result in a net cost for such energy equal to the cost of energy purchased from the existing and proposed resources.

Power Supply Planning Options – GLU-East

The GLU-East planning options investigated for this study include:

- **Option 1 Status Quo**

  No New Generation or long-term power purchase agreement ("PPA")

- **Option 2 Wind**

  50 MW/10 MW (nameplate/accredited) wind PPA

- **Option 3 RICE 35 MW & Solar 15 MW**

  35 MW reciprocating internal combustion engine ("RICE") facility with the cost of capacity discounted by the purchase of engine-generator sets from TOTE Maritime ("TOTE") as described in Section 1 and 15 MW/7.5 MW (nameplate/accredited) solar PPA.

- **Option 4 Solar**

  50 MW/25 MW (nameplate/accredited) solar PPA

- **Option 5 Combined Cycle**

  50 MW combined cycle facility (ownership share of Alliant Energy ("Alliant") 700 MW West Riverside Energy Center)

- **Option 6 Wind & RICE**

  25 MW/5 MW (nameplate/accredited) wind PPA + 25 MW RICE facility (RICE cost of capacity discounted)

- **Option 7 Wind & Solar**

  25 MW/5 MW (nameplate/accredited) wind PPA + 25 MW/12.5 MW (nameplate/accredited) solar PPA

- **Option 8 Wind & Solar & RICE**

  17 MW/3.4 MW (nameplate/accredited) wind PPA + 17 MW/8.5 MW (nameplate/accredited) solar PPA + 17 MW RICE facility (RICE cost of capacity not discounted)

- **Options 1A through 8A with DSM**

  All of the above options with DSM programs reducing capacity needs ranging from 1 MW in 2019 to 12 MW in 2023 and to 6 MW in 2038

Power Supply Planning Options – GLU-West

For GLU-West, the capacity supplied from existing contract purchases is forecasted to supply 86% of capacity requirements for the period 2019 through 2023. The energy supplied from existing contract purchases is forecasted to supply 100% of energy requirements during 2019 and 2020 and 90% to 91% of each year energy requirements for the period 2021 through 2030.

GLU-West planning options include:

- **Option 1 Status Quo**: No Long-term PPA
- **Option 2 Merge**: Merge GLU-West with GLU-East

Due to the high percentage of GLU-West energy requirements to be supplied by energy purchase contracts through 2030 as described above, no additional generation or power purchase options were investigated other than peaking capacity or potential participation in the proposed RICE generation project committee to meet MISO capacity requirements.

Forecasts and Analysis Simulations

For analysis purposes, the forecast annual electric energy and capacity requirements were allowed to fluctuate within a bandwidth based on historical fluctuations. Likewise, various other input parameters were allowed to fluctuate within their respective bandwidths as described in Section 1.

The simulations were performed at an hourly granularity that spanned the twenty-year Study Period. The options considered were compared by 20-year net present value ("NPV") and by a Least Regret Analysis as described in more detail in Section 1.

Summary of GLU-East Results

The options described above for GLU-East were analyzed and ranked by the estimated 20-year NPV of power costs and by a Least Regret Score ("LRS") as summarized in the following table for the five most cost-effective options.

Table ES-1
GLU-East Estimated Cost Summary for the Five Most Cost-Effective Options

	Option 3 RICE & Solar	Option 4 Solar	Option 1 Status Quo	Option 5 Comb. Cycle	Option 8 RICE & Solar & Wind
20-Year NPV ($M)	801	811	813	818	819
Amount above Solar Option ($M)	0	10	12	17	18
Percent above Solar Option	0.0%	1.3%	1.5%	2.1%	2.3%
Least Regret Score	5,070	81,252	75,254	75,304	114,160
Rank by LRS	1	3	2	4	5
Number of simulations with rank shown above [1]	200	137	137	137	197
Number of simulations with rank shown above or better [1]	200	200	137	137	200

[1] Out of a total of 200 simulations

The above table indicates that the most cost-effective option is the RICE & Solar option with the next four options being within 2.3% based on the estimated 20-year NPV of power costs. The estimated 20-year NPV for the five options ranges from $801 million to $819 million. These estimated NPV values are based on the median values for the 200 simulations. However, the percentage differences between NPV values for the various options taking into account all 200 simulations is not significantly different from the percentage differences shown in the above table.

Due to using the squared function as described above, the Least Regret Score is useful identifying the least-cost option, but the difference in Least Regret Scores does not provide an indication of the economic difference between options. The NPV amount is a better metric for comparing the relative difference of the options as shown in the following table.

The implementation of DSM programs reduced the estimated 20-year NPV of all of the various resource options by approximately 0.5% and did not affect the relative economic ranking of the options.

Summary of GLU-West Results

The options described above for GLU-West were assessed and ranked by 20-year NPV as summarized in the following table.

Table ES-2
GLU-West Estimated Cost Summary for the Options

	Option 1 Status Quo	Option 2 Merge with GLU-East Solar
20-Year NPV ($M)	96	125
Amount above Status Quo ($M)	0	28
Percent above Status Quo Option	0.0%	22.8%

As shown in the above table, the estimated 20-year NPV of Option 2, merging GLU-West with GLU-East, is $28 million or 22.8% more expensive than the Status Quo option. The average cost per MWh of the Status Quo option was estimated to be lower than the average cost per MWh for the merger option for all years of the 20-year Study Period. Based on this result, a regret analysis was not performed.

GLU-West has bilateral contracts for approximately 90% of its projected energy needs through 2030. GLU-West has bilateral contracts for its projected capacity needs through May 2023 and will need to procure 35 MW to meet its projected capacity needs thereafter by purchases from the MISO market, bilateral purchases, or ownership interest in a generating resource. Participation by GLU-West in a portion of the capacity associated with the RICE resource would help fix a portion of the GLU-West capacity costs to hedge against rising MISO capacity costs as generating capacity in the MISO region is retired.

Results of Analysis

This LRP Report presents the results of the most recent GLU power supply planning process. Leidos has reviewed the following planning components that have been used by GLU in preparing the GLU LRP. The components reviewed by Leidos include:

- Load Forecasting Model
- Midwest Independent System Operator ("MISO") locational marginal pricing ("LMP") Forecast
- GLU Capacity Requirements Model
- GLU Energy Generation Dispatch Model
- GLU Least Regret Model
- Regulatory Environment
- Renewable Energy Resources
- GLU Existing Power Supply Portfolio in above models
- Power Supply options

Key Assumptions and Considerations

The following assumptions and considerations were used in the preparation of the GLU planning analysis:

- The load forecast for both GLU-East and GLU-West were relatively flat over the Study Period reflecting historical trends.
- Typically, the participation in an ownership share of a large natural gas-fired combined cycle generating resource is dependent on the participation by and timing needs of other parties. Alliant has offered an ownership share in the 700 MW natural gas-fired, combined cycle West Riverside Energy Center project, which is under construction with an expected in-service date in 2020.
- A small stand-alone natural gas-fired RICE resource that GLU could construct independently with no other parties participating was included in the analysis. Estimated costs were based on procuring unused, surplus engine-generator sets at a discounted cost from TOTE.
- Other resource options included in the study were purchases of energy from wind and solar resources. The estimated purchase costs were based on recent proposals received by GLU and the scheduled termination of the wind production tax credit and the reduction in the solar investment tax credit.
- Annual fixed and variable costs for the resources are described in Section 1.
- Any capacity deficiencies not met by the existing resources or resource additions would be met by purchasing capacity from the MISO market or MISO participants.

- On May 1, 2018, the USEPA informed the state of Wisconsin that a 2015 ozone nonattainment area would be designated for a portion of Manitowoc County from Lake Michigan to a north-south line several miles inland, which includes the MPU CFB facilities. Per discussions with the Wisconsin Department of Natural Resources ("WDNR"), MPU does not expect any impact on existing facilities within the 2015 ozone nonattainment area such as the MPU CFB facilities. The impact of this ozone nonattainment designation should be reflected in the estimated construction and operating costs of any new resource planned for construction within this area.
- The MPU CFB annual fixed and variable O&M costs are estimated to range from $15.0 million to $16.2 million through the end of the lease period, which includes amounts for depreciation to fund upgrades. If the costs significantly exceed such amounts due to unexpected expenditures for a major overhaul or to meet the requirements of the 2015 ozone nonattainment classification, it is assumed the lease would be re-evaluated at that time.
- The fixed costs per kW for capacity are estimated to be within the following ranges for the Study Period:
  - MISO Market — $1.55 to $9.70 per kW-month
  - RICE facility — $5.10 to $5.35 per kW-month
  - Alliant Combined Cycle — $9.00 to $11.25 per kW-month
  - MPU CFB — $17.20 to $17.30 per kW-month
  - WPS[3] — $17.71 to $22.46 per kW-month
  - WEPCo[4] — $28.18 to $35.28 per kW-month
- The resource options were evaluated using a Least Regret Analysis as described herein and an NPV analysis.
- This study used the current MISO capacity credit amounts of 15% of nameplate capacity for wind and 50% of nameplate capacity for solar resources. However, MISO expects that as the penetration of wind and solar resources increases in the MISO region, the capacity credits for wind and solar resources will decrease. This is expected to be due to the inherent nature of wind and solar resources that rely on variable wind and solar energy sources and the resulting inability of those resources to reliably serve an effectively wider peak load period as described more fully in Section 1.2.1 of this report. It is not known how quickly and to what extent the associated capacity credit amounts might be affected.

[3] WPS is Wisconsin Public Service Company
[4] WEPCo is Wisconsin Electric Power Company

Key Conclusions and Recommendations

GLU should consider the following conclusions and recommendations along with its other business, financial, economic, and regulatory considerations.

Conclusions

- The methodology used by GLU for the power supply planning was found to be sound and consistent with prudent power supply planning procedures.
- GLU-East has a need of additional 40 MW of capacity beginning with the 2023/2024 MISO planning year and increasing to 159 MW by 2038.
- GLU-East does not need additional renewable energy resources until 2033 with the current Wisconsin renewable energy credit regulations.
- For GLU-East, the 35 MW RICE option with procurement of engine-generator sets at a discounted amount in conjunction with 15 MW of solar capacity is the option with the lowest estimated 20-year NPV and Least Regret Score.
- The RICE & Solar option, for which engine-generator sets at a discounted cost will not always be available, provides GLU-East with an opportunity to fix a portion of its capacity costs to hedge against rising MISO capacity costs as existing MISO resources are retired.
- Based on an estimated 20-year NPV analysis, the other options ranged from 1.3% ($10 million) to 6.0% ($48 million) more expensive than the RICE & Solar option.
- GLU-West has projected capacity needs of 35 MW from 2023 through the end of the Study Period.
- GLU-West has projected energy needs of approximately 18,000 MWh per year (or about 10% of the aggregate energy requirements) through 2030 and 185,000 MWh per year (or 100% of the aggregate energy requirements) through the end of the Study Period.
- GLU-West has under contract a wind resource that is expected to meet 126% of its projected annual renewable energy requirements through the end of the Study Period with the current Wisconsin renewable energy credit regulations.
- For GLU-West, the Status Quo option is 22.8% or $28 million less expensive on an estimated 20-year NPV basis than the GLU-West Merge with GLU-East option.
- The implementation of DSM reduced the 20-year NPV of all options by about 0.5%, but did not affect the relative economic results for the options.

Recommendations

- After the GLU Board has accepted the recommendations, a GLU project committee should be created to pursue acquisition of the 35 MW of RICE capacity for GLU-East and GLU-West members.
- A GLU project committee should be created to pursue acquisitions of distribution-connected solar resources for GLU-East and GLU-West members.
- In conjunction with the above, enter into a non-binding agreement to acquire three 11.7 MW RICE engine-generator sets available at a discounted price.
- Authorize activation of Phase 3 of the GLU Long Range Power Supply Analysis for siting the RICE resource, preparing preliminary layouts, and confirming budgetary and annual costs in this study.
- Submit a MISO generator interconnection request after the RICE resource site has been selected and confirmed.
- Prepare applications to the Public Service Commission of Wisconsin ("PSCW") and WDNR.
- After approvals have been received, prepare design and procurement documents.

Section 1
REVIEW OF GLU POWER SUPPLY PLANNING

1.1 Introduction

GLU is a municipal power agency that supplies wholesale power to its members that participate in GLU-East via the East Power Supply Committee of GLU and GLU-West via the West Power Supply Committee of GLU.

1.1.1 GLU-East

GLU-East has the following participating power supply members:

- Badger Power Marketing Agency (City of Shawano Utilities and Clintonville Utilities)
- Kiel Electric Utility
- Manitowoc Public Utilities (load following up to 77 MW)
- Wisconsin Rapids Water & Light
- Stratford Water & Electric (starting 2020) [5]

GLU-East has an estimated aggregate peak load of 205 MW in 2019, including 77 MW of Manitowoc Public Utilities (MPU) load. MPU has leased generation to GLU through the end of 2026, including two circulating fluidized bed (CFB) boilers, which burn primarily petroleum coke and some waste wood, totaling 77 MW of capacity as follows:

Unit 8 (Boiler 8 with Turbine 5 or Turbine 6)	22 MW
Unit 9 (Boiler 9 with Turbine 9)	55 MW
Total	77 MW

1.1.2 GLU-West

GLU-West has the following participating power supply members:

- Bangor Municipal Utilities
- Cornell Municipal Electric Utilities
- Medford Electric Utilities
- Trempealeau Municipal Electric Department

GLU-West has an estimated aggregate peak load of 33 MW in 2019.

[5] The Stratford electric load, which has an approximate peak of 3 MW, was not included in this study.

1.1.3 GLU Planning Process

GLU plans for and provides wholesale power to its members separately for the GLU-East members and the GLU-West members. GLU uses the same LRP methods for both GLU-East and GLU-West. The components of the LRP process include:

- Load Forecasting Model
- MISO LMP Forecasting Model
- GLU Capacity Requirements Model
- GLU Energy Generation Dispatch Model
- GLU Least Regret Model
- Regulatory Environment
- Renewable Power Supply Resources
- GLU Existing Power Supply Portfolio in above models
- Power Supply options

1.2 Planning options

1.2.1 Planning options for GLU-East

The GLU-East planning options investigated in this analysis include:

- **Option 1 Status Quo**

  No New Generation or PPA
- **Option 2 Wind**

  50 MW/10 MW (nameplate/accredited) wind PPA
- **Option 3 RICE 35 MW and Solar 15 MW**

  35 MW RICE facility with the cost of capacity discounted by the purchase of engines from TOTE as described below and 15 MW/7.5 MW (nameplate/accredited) solar PPA.
- **Option 4 Solar**

  50 MW/25 MW (nameplate/accredited) solar PPA
- **Option 5 Combined Cycle**

  50 MW combined cycle facility (ownership share of Alliant 700 MW West Riverside Energy Center)
- **Option 6 Wind & RICE**

  25 MW/5 MW (nameplate/accredited) wind PPA + 25 MW RICE facility (RICE cost of capacity discounted)

- **Option 7 Wind & Solar**

  25 MW/5 MW (nameplate/accredited) wind PPA + 25 MW/12.5 MW (nameplate/accredited) solar PPA

- **Option 8 Wind & Solar & RICE**

  17 MW/3.4 MW (nameplate/accredited) wind PPA + 17 MW/8.5 MW (nameplate/accredited) solar PPA + 17 MW RICE facility (RICE cost of capacity discounted)

- **Options 1A through 8A with DSM**

  All of the above options with DSM programs reducing capacity needs ranging from 1 MW in 2019 to 12 MW in 2023 and to 6 MW in 2038

Existing Contract Purchases – GLU-East

The following table summarizes the existing contract purchases included in all options for GLU-East.

Table 1-1
GLU-East Contract Purchases

	Energy Block or Capacity Purchase	Period
NextEra or TransAlta	25 MW ATC[1] energy	2019 - 2022
NextEra or TransAlta	35 MW peak energy	2019 - 2022
Dairyland Power Coop	30 MW capacity	2019 - 2023
Marshfield Utilities	14 MW capacity	2019 - 2024
MPU-GLU Lease	77 MW capacity	2019 - 2026
WEPCo [2]	32.4 MW capacity	2019 - 2029
WPS [2]	59.4 MW capacity	2019 - 2031
Lakeswind PPA[3]	13.3 MW capacity	2019 - 2034

[1] ATC means around the clock

[2] Nominations selected equal to minimums allowed by contract due to the relatively high capacity costs

[3] PPA means power purchase agreement

Market Capacity Purchase

All of the above options include the purchase of market capacity as needed to meet the GLU-East peak load requirements not met by the other resources as the peak load varies for each of the 200 random draws.

Existing Renewable Resource Purchases

GLU-East members have 13.3 MW of aggregate nameplate capacity in the Lakeswind Wind Project, which annually supplies on average approximately 45,000 MWh of energy or 40% of the 111,100 MWh aggregate GLU-East renewable energy requirement. In addition, GLU-East received renewable energy credits in conjunction with its purchase of power from WP&L, from WEPCo, and from the MPU CFB facility due to using waste paper pellets for a portion of the fuel source.

After 2026, with the cancellation of the GLU-MPU capacity lease and the reduction of the MPU load served by GLU to 13 MW, the 45,000 MWh output of Lakeswind Energy Project supplies 64% of the 70,100 MWh aggregate GLU-East renewable energy requirement. The GLU-East renewable energy requirements are described below under Section 1.8.

New Renewable Resource Purchases

The estimated outputs of the wind resource options were based on the Lakeswind Wind Project and the estimated output of the solar resource options were based on solar insolation data from the National Oceanic and Atmospheric Administration.

GLU received proposals in 2018 for various wind and solar PPAs. The characteristics of the proposed wind and solar PPAs used in this analysis are summarized in the following table.

Table 1-2
Estimated Wind and Solar PPA Characteristics

	Wind PPA [1]	Solar PPA [2]
Size	25 MW or 50 MW	25 MW or 50 MW
Annual Capacity Factor	41%	18%
Pricing Node	MINN.HUB	ATC Holland
MISO Capacity Credit [3]	15%	50%
2021 – 2022 PPA Cost ($ per MWh)	$40.20	$50.14
2023 – 2025 PPA Cost ($ per MWh)	$40.70	$50.14
2026 – 2030 PPA Cost ($ per MWh)	$41.70	$50.14
2031 – 2038 PPA Cost ($ per MWh)	$46.95	$50.14
Approximate historical average LMP below WPS.GLU node LMP	$7.00	$3.00

[1] Wind PPA prices 2021-2030 are based on a 10-year PPA for a wind project in northwest Iowa. Prices for 2031-2038 are based on a 20-year PPA for a wind project in southwest Wisconsin.

[2] Solar PPA prices are based on a 20-year PPA for a solar project near Sheboygan, WI.

[3] Current capacity credits in MISO. See discussion below concerning expected decrease in capacity credits as wind and solar penetration increase in the MISO region.

The cost estimates shown in Table 1-2 are based on 2018 proposals by various renewable energy companies that have been adjusted to reflect costs without the $24 per MWh production tax credit for wind projects starting construction after 2019 and a reduction of the investment tax credit for solar from 30% to 10% for commercial solar projects constructed after 2021.

As shown in Table 1-2, the delivery point for the wind projects output and the solar project output are at MINN.HUB and ATC Holland nodes, respectively, and based on historical data, the average LMP at MINN.HUB and at ATC Holland have been approximately $7.00 per MWh and $3.00 per MWh, respectively, less than the WPS.GLU node. The analysis models the sale of the wind output or solar output into the MINN.HUB or ATC Holland node, respectively, with the simultaneous purchase of power from the WPS.GLU node, resulting in a net increase in cost of $7.00 per MWh on average for wind and $3.00 per MWh on average for solar. With the recent installation of CapX2020 transmission facilities, these LMP differentials are expected to decrease, but there are no data yet to confirm this expectation.

Table 1-2 above provides the current MISO capacity credit amounts that were used for this study. However, MISO expects that as the penetration of wind and solar resources increases in the MISO region, the capacity credits for wind and solar resources will decrease. This is expected to be due to the inherent nature of wind and solar resources that rely on variable wind and solar energy sources.

The reason for the above decreasing capacity credits is expected to be due to the increasing width of the peak period that would need to be served by the above resources as more of these resources are installed and commissioned in the MISO footprint. As more of the peak load is served by wind and solar resources, the net peak load (not served by wind and solar) will be reduced. There will be shoulder hours whose load will then be equal to the net peak load (not served by wind and solar). This effectively widens the peak period that needs to be served.

Due to the inherent nature of the output of wind and solar, the amount of capacity (relative to nameplate) is expected to be less in the hours after and/or before the current peak hours. For example, as the sun sets, solar output would continue to decrease after the current peak load hours.

The above would result in a decrease in the capacity credit for wind and solar resources since they would not be able to serve the widening peak hours at the same level as the current peak hours.

The above expectation concerning the decrease capacity credits in wind and solar resources has been confirmed by Brian Tulloh, Executive Director, External Affairs-North Region of MISO and a June 5, 2018, MISO workshop Renewable Integration Impact Assessment ("RIIA"). The RIIA projects the effective load-carrying capability ("ELCC") for solar resources and wind resources will decrease as the penetration of those resources increases in the MISO region. The effect on ELCC for wind resources is expected to be significantly less than that for solar resources. The drop in ELCC for wind and solar resources is expected to result in a reduction of the associated MISO capacity credit amounts for wind and solar resources. It is not known how quickly the penetration rates of wind and solar resources will increase in the MISO region and how quickly and to what extent the associated capacity credit amounts might be affected.

1.2.2 Planning options for GLU-West

Two options were analyzed for GLU-West:

- **Option 1: Status Quo without New Generation or PPAs**

  Maintain a separate power supply pool and continue purchases of capacity and energy under existing contracts.

- **Option 2: Combined GLU-West with GLU-East**

  Merge the GLU-West power supply pool with the GLU-East power supply pool, continue the purchases of capacity and energy under existing GLU-West contracts, and take all requirements from the merged pool.

For GLU-West, the capacity supplied from existing contract purchases described below is forecasted to supply 86% of capacity requirements for the period 2019 through 2023. The energy supplied from existing contract purchases is forecasted to supply 100% of energy requirements during 2019 and 2020 and 90% to 91% of each year energy requirements for the period 2021 through 2030. Based on this, additional power supply options other than the above two were not investigated.

The existing GLU-West capacity and energy contracts include the following:

Table 1-3
GLU-West Contract Purchases and Termination Dates

	Capacity or Energy Block	Period
NSP	20 MW ATC energy	2019
NSP	10 MW peak energy	2019
TransAlta	15 MW ATC energy	2020
TransAlta	15 MW peak energy	2020
TransAlta	15 MW ATC energy	2021
TransAlta or NextEra	10 MW peak energy	2021
NextEra	15 MW ATC energy	2022 - 2030
NextEra	10 MW peak energy	2022 - 2030
NextEra	33.5 MW	2018 – 2019
EDF Trading	30 MW	2019 - 2020
NSP	30 MW	2020 - 2021
Dairyland	30 MW	2021 - 2023

Market Capacity Purchase

The above options include the purchase of market capacity as needed to meet the peak load requirements (including estimated losses and planning reserve capacity of 9.3%) not met by the other resources as the peak load varies for each of the 200 random draws.

Existing Renewable Resource Purchases

GLU-West members have 8.1 MW of aggregate nameplate capacity in the Lakeswind Wind Project, which annually supplies on average approximately 27,500 MWh of energy or 126% of the 21,800 MWh aggregate GLU-West renewable energy requirement.

1.3 Load Forecasting Model Review

1.3.1 Forecast of Energy and Peak Demand

Load and demand forecasting was done at the member utility level and aggregated into the respective group total. The load and demand forecast was conducted as follows.

Step 1

Historical data for numbers of customers and annual consumption by rate class were acquired for each member utility. The above data was analyzed by linear regression techniques to identify the historical trends in the form of linear models. These models were used to forecast the annual number of customers and annual consumption per customer by rate class for each utility for the Study Period. The forecast number of customers was applied to the forecast number of customers and aggregated for the members.

The historical variations in the data were used to set the ranges for the Monte Carlo analysis.

Step 2

A set of 200 annual energy requirements forecasts were calculated for each group (GLU-East and GLU-West) using that group's aggregate forecast (as calculated in Step 1) as a basis.

Step 3

For each of the 200 draws for each group, the hourly load was simulated from the forecasted annual energy requirements for each year by means of an algorithm that simulated hourly load as a percent of annual energy requirements based on factors such as month of year, day of week, hour of day, and NERC holidays. This algorithm used a member-specific load duration curve based on an average of the most recent three-year period correlated by day of the week. For each of the 200 draws performed for all of the members within the group, the hourly member load was aggregated to produce a GLU load duration curve for each year.

For the options in which GLU would serve all MPU load up to 77 MW, for each hour of each year of the 200 random samples, the GLU load aggregate included MPU load up to 77 MW.

1.3.2 Summary of GLU-East Forecast

The following table provides a summary of the 200 GLU-East historical and forecast load draws, including up to 77 MW of MPU load through the end of 2026 and 13 MW after 2026. As described above, the 200 load draws were used for the Monte Carlo analysis.

Table 1-1
GLU-East Historical and Forecast Load (GWh)

Year	10th Percentile	Historical or Median	90th Percentile
Historical			
2012		1,298	
2013		1,299	
2014		1,312	
2015		1,291	
2016		1,296	
2017		1,290	
2018		1,352	
Forecast			
2019	1,247	1,281	1,330
2020	1,253	1,291	1,331
2021	1,261	1,297	1,340
2022	1,261	1,303	1,340
2023	1,275	1,307	1,348
2024	1,277	1,312	1,349
2025	1,291	1,323	1,362
2026	1,284	1,322	1,359
2027	856	889	926
2028	859	891	930
2029	867	894	927
2030	866	898	933
2031	876	906	942
2032	874	907	949
2033	876	912	947
2034	890	923	959
2035	891	923	967
2036	891	924	963
2037	904	936	970
2038	910	937	972

The data in the above table indicates the historical average compound load growth for GLU-East from 2012 to 2018 was 0.7%, the 7-year average compound growth for the median forecast load from 2019 to 2026 is 0.4%, and the 11-year average compound growth for the median forecast load from 2026 to 2038 is 0.5%.

1.3.3 Summary of GLU-West Forecast

The following table provides a summary of the 200 GLU-West historical and forecast load draws. As described above, the 200 load draws were used for the Monte Carlo analysis.

Table 1-2
GLU-West Historical and Forecast Load (GWh)

Year	10th Percentile	Historical or Median	90th Percentile
Historical			
2014		190	
2015		189	
2016		186	
2017		183	
2018		187	
Forecast			
2019	174	181	187
2020	174	181	188
2021	173	180	190
2022	174	180	187
2023	174	180	187
2024	174	181	188
2025	174	181	188
2026	174	182	188
2027	175	182	190
2028	175	182	190
2029	175	182	188
2030	175	182	188
2031	176	183	190
2032	176	182	191
2033	176	184	190
2034	177	184	192
2035	177	185	192
2036	177	185	193
2037	178	186	194
2038	179	186	195

The data in the above table indicate the historical average compound load growth for GLU-West from 2014 to 2018 was -0.4% and the 19-year average compound growth for the median forecast load from 2019 to 2038 is 0.2%.

1.4 GLU Capacity Requirements Model

1.4.1 Capacity Requirements for GLU-East

The following tables provide a summary of the GLU-East capacity requirements for the median forecast. For other forecasts selected by the 200 draws, the market purchased capacity was adjusted on an annual basis to meet the capacity requirement. The capacity requirement equals the peak load less 5% to account for diversity with the MISO peak load plus 8% to account for losses and the MISO planning reserves margin requirement. The short-term capacity purchases and sales are not shown in the following tables.

The following table is a summary of the GLU-East Capacity Requirements for the Status Quo option.

Table 1-6
Forecast GLU-East Median Capacity Requirements (MW) Status Quo Option

Period	Peak Load	Capacity Requirement [1]	WE and WPS [2]	MPU CFB [3]	Purchased Capacity [4]
Historical					
2012	220				
2013	220				
2014	208				
2015	204				
2016	211				
2017	207				
2018	220				
Forecast					
2019 – 2026	205 - 208	213 - 216	91	77	45 – 48
2027 – 2028	146	152	91	0	61
2029 – 2031	146 - 148	152 – 154	59	0	93 – 95
2032 – 2038	148 - 153	154 - 159	0	0	154 - 159

[1] Capacity Requirement equals peak load less MISO diversity adjustment plus loss and planning reserves.
[2] The WE capacity is 32 MW through 2028 and the WPS capacity is 59 MW through 2031.
[3] MPU Unit 8 capacity of 22 MW and Unit 9 capacity of 55 MW.
[4] Purchased Capacity is from the MISO capacity market or bilateral purchases.

As shown in the above table, GLU-East is forecast to require from 45 MW to 159 MW of purchased capacity over the Study Period under the Status Quo option.

The following table is a summary of the GLU-East Capacity Requirements showing a new 50 MW resource plus capacity purchases. The 50 MW resource options include solar, wind, a RICE resource, and a combined cycle resource as described above.

Table 1-7
Forecast GLU-East Median Capacity Requirements (MW) with New 50 MW Generation Resource Options

Period	Peak Load	Capacity Requirement [1]	WE and WPS [2]	MPU CFB [3]	New Resource [4]	Purchased Capacity [5]
Historical						
2012	220					
2013	220					
2014	208					
2015	204					
2016	211					
2017	207					
2018	220					
Forecast						
2019 – 2026	205 - 208	213 - 216	91	77	50	
2027 – 2028	146	152	91	0	50	11
2029 – 2031	146 - 148	152 – 154	59	0	50	43 – 45
2032 – 2038	148 - 153	154 - 159	0	0	50	104 - 109

Notes:
[1] Capacity Requirement equals peak load less MISO diversity adjustment plus loss and planning reserves.
[2] The WE capacity is 32 MW through 2028 and the WPS capacity is 59 MW through 2031.
[3] MPU Unit 8 capacity of 22 MW and Unit 9 capacity of 55 MW.
[4] New Resource Options are described in Section 1.2.1.
[4] Purchased Capacity is from the MISO capacity market or bilateral purchases.

As shown in the above table, with the installation of 50 MW of generating capacity, the amount of purchased capacity required for GLU-East over the Study Period is reduced to a range of 11 MW to 109 MW.

1.4.2 Capacity Requirements GLU-West

The following tables provide a summary of the GLU-West capacity requirements for the median forecast. For other forecasts selected by the 200 draws, the market purchased capacity was adjusted on an annual basis to meet the capacity requirement. The capacity requirement equals the peak load less 5% to account for diversity with the

MISO peak load plus 8% to account for losses and the MISO planning reserves margin requirement.

The following table is a summary of the GLU-West Capacity Requirements for the Status Quo option.

Table 1-8
Forecast GLU-West Median Capacity Requirements (MW) Status Quo

Period	Peak Load	Capacity Requirement [1]	Purchased Capacity [2]
Historical			
2014	35		
2015	34		
2016	35		
2017	35		
2018	35		
Forecast			
2019 - 2038	34	36	36

[1] Capacity Requirement equals peak load less MISO diversity adjustment plus losses and planning reserves.
[2] Purchased Capacity represents 30 MW under contract for 2019 through 2023 with the balance from the MISO capacity market.

1.5 GLU Energy Generation Dispatch Model

1.5.1 Introduction

Analytically, all calculations were performed at the hourly level. Load forecasting, pricing of variables, facility dispatch, etc., were computed in 200 simulations of 20 years of 8760 hours each. The development of the 200 random load forecast samples is described in the load and demand forecasting steps above. For the pricing of the variables listed below, 200 random samples were taken in the bandwidths described below. MATLAB software was utilized to perform the data manipulation and calculation involved.

1.5.2 Selecting Natural Gas Price Samples

Natural gas prices were selected by 200 random draws from a bandwidth around a baseline trajectory of annual natural pricing derived from monthly Henry Hub natural gas futures (2019-2030) extrapolated by the 2019-2030 average annual rate of increase to fit the 2038 planning horizon of the study. The bandwidth was defined by the historical fluctuations in the price of natural gas.

Table 1-9
Forecast Annual Natural Gas Prices ($ per MMBTU)

Year	10th Percentile	Median	90th Percentile
2019	1.93	2.63	3.73
2020	1.96	2.67	3.48
2021	2.10	2.84	3.65
2022	2.04	2.83	3.67
2023	2.15	2.79	3.88
2024	2.18	3.02	4.14
2025	2.45	3.16	4.26
2026	2.21	2.98	4.13
2027	2.34	3.18	4.23
2028	2.43	3.33	4.25
2029	2.51	3.44	4.66
2030	2.46	3.38	4.43
2031	2.49	3.53	4.71
2032	2.68	3.58	5.03
2033	2.71	3.65	5.11
2034	2.71	3.71	5.02
2035	2.90	3.96	5.15
2036	3.00	3.90	5.14
2037	2.96	4.05	5.39
2038	2.83	4.10	5.71

The forecast amounts in the above table indicate the 19-year average compound growth for the median forecast natural gas price from 2019 to 2038 is 2.4%.

1.5.3 Selecting LMP Price Samples

LMPs were forecast based on the natural gas price forecast and the historical correlation between natural gas prices and LMPs. The price of natural gas-fired generation is expected to be the generation resource at the margin that sets the LMPs for the foreseeable future. Also, correlating LMPs with natural gas prices helps avoid overstating the net revenues associated with sales of energy into the MISO market from owned resources, which could occur if a natural gas price for generation is used that is lower than the natural gas price that determines the MISO LMP.

As described below, the LMPs were also adjusted for the cost of CO2 fees based on the amount of CO2 emitted by natural gas-fired generation, which is expected to set the LMPs during the Study Period.

The following table provides a summary of the average annual LMP prices chosen for the Monte Carlo analysis without any CO2 fees.

Table 1-10
Summary of Average Annual MISO LMP Forecasts without Adjustment for CO2 fees

($ per MWh)

Year	10th Percentile	Median	90th Percentile
2019	22.44	26.78	32.68
2020	22.18	26.96	32.17
2021	23.27	27.94	33.07
2022	22.77	27.31	33.79
2023	22.72	27.90	33.64
2024	24.01	28.45	34.51
2025	23.93	29.06	34.56
2026	23.69	28.15	34.58
2027	24.12	28.52	35.12
2028	23.99	29.20	35.70
2029	24.83	29.96	37.01
2030	24.78	29.46	35.82
2031	25.86	30.58	36.94
2032	25.61	30.40	36.78
2033	25.32	30.69	37.19
2034	25.66	30.40	37.54
2035	26.62	31.50	38.37
2036	26.86	31.91	38.09
2037	27.21	31.99	38.28
2038	26.39	32.95	38.75

The forecast amounts in the above table indicate the 19-year average compound growth for the median forecast MISO LMPs (without an adjustment for CO2 fees) from 2019 to 2038 is 1.1%.

The following table provides a summary of the average annual LMP prices chosen for the Monte Carlo analysis with CO2 fees. The forecast of CO2 fees is described in the following section of this report.

Table 1-11
Summary of Average Annual MISO LMP Forecasts with Adjustment for CO2 fees

($ per MWh)

Year	10th Percentile	Median	90th Percentile
2019	22.44	26.78	32.68
2020	22.18	26.96	32.17
2021	23.27	27.94	33.07
2022	22.77	27.31	33.79
2023	22.72	27.90	33.64
2024	24.01	28.45	34.51
2025	23.93	29.06	34.56
2026	23.69	28.15	34.58
2027	27.97	33.66	43.00
2028	27.71	35.02	42.91
2029	28.29	36.02	45.17
2030	27.84	35.55	43.68
2031	27.96	35.90	47.62
2032	29.59	36.16	45.54
2033	28.28	36.99	47.39
2034	29.57	36.76	44.70
2035	30.03	37.88	47.12
2036	30.07	38.82	47.37
2037	31.14	38.09	47.64
2038	30.28	39.07	51.37

The forecast amounts in the above table indicate the 19-year average compound growth for the median forecast MISO LMPs from 2019 to 2038 is 2.0%.

1.5.4 Selecting CO2 Emission Price Samples

CO2 emissions were priced at $0/ton until 2027, when a baseline price of $11.80 per ton was initiated, escalating at 1.2% per year. A bandwidth from $0 to four times the baseline was created around this baseline forecast to reflect the considerable uncertainty around this parameter. For the simulation, CO2 emission prices were selected by 200 random draws within this bandwidth for each year of the Study Period. Subject to the above bandwidth, for each set of the 200 draws, there was no limitation on the price of CO2 emissions from year to year. The price could be at the bottom of the bandwidth one year and the top of the bandwidth the following year.

The CO2 emission prices used for the Monte Carlo analysis are summarized in the following table.

Table 1-12
Summary of Annual CO2 Emission Fee Forecast ($ per Ton)

Year	10th Percentile	Median	90th Percentile
2019	-	-	-
2020	-	-	-
2021	-	-	-
2022	-	-	-
2023	-	-	-
2024	-	-	-
2025	-	-	-
2026	-	-	-
2027	2.20	11.81	34.83
2028	2.49	11.72	34.25
2029	2.34	13.13	36.76
2030	1.93	11.11	35.87
2031	1.81	10.65	34.80
2032	1.97	11.17	36.54
2033	2.54	12.94	38.65
2034	1.63	10.70	37.48
2035	3.71	12.77	38.40
2036	2.83	11.87	38.71
2037	3.49	12.81	39.81
2038	2.36	13.45	40.81

The data in the above table indicates the 11-year average compound growth for the median forecast CO2 fee from 2027 to 2038 is 1.2%.

1.5.5 Selecting Solid Fuel and Production Cost Samples

Projections for the solid fuel (petroleum coke used by the MPU CFB boilers) and for associated production costs were developed by using current production costs as a reference point and constructing a base cost projection based on the trajectory of monthly CME coal futures (2016-2018). The bandwidth around the base forecast was based on the historical fluctuation in cost.

The forecast of production costs used for the analysis are summarized in the following table.

Table 1-13
Forecast of Solid Fuel Prices for MPU CFB Facilities ($ per MWh)

Year	10th Percentile	Median	90th Percentile
2019	43.69	44.81	45.90
2020	44.99	46.48	48.30
2021	46.47	48.36	50.48
2022	47.98	50.49	52.89
2023	49.57	52.43	55.20
2024	51.25	54.68	58.12
2025	53.28	56.75	60.90
2026	55.49	59.30	63.36
2027	57.09	61.73	66.31
2028	59.64	64.29	68.72
2029	61.75	66.69	71.78
2030	64.24	69.35	74.67
2031	66.40	72.09	77.92
2032	68.70	75.03	81.58
2033	71.47	78.18	84.84
2034	73.24	80.95	88.51
2035	76.04	84.23	91.99
2036	79.15	87.59	96.79
2037	81.82	91.06	100.94
2038	84.72	94.68	105.54

1.5.6 Selecting Market Capacity Cost Samples

The bandwidth for market capacity was set at $1 per kw-month for the lower band and cost of new entry ("CONE") as estimated for new combustion turbines by MISO for the upper band with each escalated at 2% per year. Market capacity cost for the simulations were sampled (200 random draws) from a uniform distribution within that bandwidth.

The forecast of market capacity prices used for the Monte Carlo analysis are summarized in the following table.

Table 1-14
Forecast of Market Capacity Prices ($ per kW-month)

Year	10th Percentile	Median	90th Percentile
2019	1.65	4.23	6.98
2020	1.55	4.22	6.99
2021	1.68	4.51	6.97
2022	1.94	4.72	7.30
2023	1.85	4.49	7.43
2024	1.89	4.98	7.65
2025	1.99	4.51	7.53
2026	1.85	4.49	7.71
2027	2.20	5.02	8.09
2028	1.81	4.82	8.13
2029	1.95	5.50	8.41
2030	1.97	4.99	8.43
2031	2.47	5.92	8.70
2032	2.40	5.64	8.94
2033	2.03	5.42	9.36
2034	2.19	5.46	9.26
2035	2.32	5.54	9.30
2036	2.43	5.94	9.69
2037	2.50	6.30	9.62
2038	2.44	6.44	9.51

1.5.7 Fixed Costs

The following are the fixed costs for various resources included in the analysis for each of the options.

- **MPU CFB Units**: Fixed costs (including labor, O&M, A&G, and depreciation) ranging from $15.9 million in 2017 to $16.0 million in 2026.
- **RICE Resource**: Fixed costs are based on a capital cost estimate from the November 2016 U. S. Energy Information Administration report *Capital Cost Estimates for Utility Scale Electricity Generating Plants* for an 85 MW RICE facility adjusted for inflation at 2% per year to a 2021 in-service date and adjusted for a reduction in the cost of the engine-generator set based on unused surplus equipment available from TOTE for an estimated total installed cost in 2021 of $945 per kW.

The TOTE equipment available to GLU includes three Wartsila 12V50DF RICE engine-generator sets each rated for an output of 11,700 kW for a combined output of 35.1 MW. The proposed $7.5 million procurement and installation cost represents an estimated $13 million savings over a comparable new unit.

The fixed costs are estimated at $5.11 per kW-month in 2021 increasing to $5.34 per kW-month by 2038 based on applying to the estimated installed cost a combined debt service and A&G rate of 4.41%, fixed O&M of 0.40%, and payment in lieu of tax rate of 1.67%.

- **CC Resource**: Fixed costs are based on data provided by Alliant for the 700 MW West Riverside Energy Center natural gas-fired, combined cycle resources near Beloit. Participation by GLU would include the following:
  - Ownership investment at book value (approximately $1,000 per kW) on about the commercial operation date in 2020
  - GLU would assign the capacity to Alliant
  - Alliant would be responsible for the associated capacity requirement of GLU
  - GLU would be able to purchase at any time energy from Alliant up to the amount of capacity purchased
  - GLU would purchase the energy at the average system cost of energy produced by Alliant. Alliant did not provide estimates of average system energy costs so the estimated fuel cost plus variable and fixed O&M were used as a proxy.
  - The contract for capacity and energy would have an initial 10-year period with a 5-year notice of cancellation thereafter.
  - If the contract is cancelled by GLU, Alliant would repurchase the capacity at book value
  - If Alliant cancels the contract, GLU would retain ownership in the combined cycle plant and would be able to sell the energy output into the MISO market similar to a typical ownership approach while paying fuel, O&M, and R&R costs.
- **Purchased Capacity**: Fixed costs for the purchase of capacity from WPS and WEPCo. These quantities are based on contract formulas and were projected by the respective utility to the end of the contract period. The WPS capacity cost ranged from $17.71 per kW-month in 2019 to $22.46 per kW-month in 2031. The WEPCo capacity cost ranged from $28.19 per kW-month in 2019 to $35.28 per kW-month in 2029.

1.5.8 Variable Costs

Variable costs were estimated by resource as follows:

MPU CFB resources

Unit 8 heat rate ("HR"):
MMBTU = (0.178)*MW^2 + (7.128)*MW + 79.06

Unit 8 Output

5 MW	HR = 23.8 MMBTU per MWh
10 MW	HR = 16.7 MMBTU per MWh
15 MW	HR = 14.9 MMBTU per MWh
22 MW	HR = 14.5 MMBTU per MWh

Unit 9 heat rate:
MMBTU = (0.0428) * MW^2 + 7.200) * MW + 140.30

Unit 9 Output

18 MW	HR = 15.8 MMBTU per MWh
30 MW	HR = 13.2 MMBTU per MWh
40 MW	HR = 12.4 MMBTU per MWh
55 MW	HR = 12.1 MMBTU per MWh

Variable O&M included with fixed costs

RICE Resource

Heat rate:	7.7 MMBTU per MWh @ 100% load
	8.1 MMBTU per MWh @ 75% load
	8.7 MMBTU per MWh @ 50% load
Variable O&M	$5.85 per MWh escalated at 2% per year

Combined Cycle Resource

Heat rate:	6.8 MMBTU per MWh
Variable O&M	$3.50 per MWh escalated at 2% per year

Lakeswind Resource

Variable O&M $38/MWh fixed price per contract

1.5.9 CO2 Emissions

CO2 emissions were estimated by resource as follows:

MPU CFB Resources

225 lbs. CO2 per MMBTU of petroleum coke
12.3 MMBTU of petroleum coke per MWh generated
1.38 tons per MWh

Combined Cycle Resource

117 lbs. CO_2 per MMBTU of NG
6.80 MMBTU of NG per MWh generated
0.40 tons per MWh

RICE Resource

117 lbs. CO_2 per MMBTU of NG
7.7 MMBTU of NG per MWh generated @ 100% load
8.1 MMBTU of NG per MWh generated @ 75% load
8.7 MMBTU of NG per MWh generated @ 50% load
0.45 to 0.51 tons per MWh

1.5.10 Resource Operating Limits

The operating limits used in the dispatch simulation for each resource were as follows:

MPU Unit 8

- Minimum of 5 MW (23% of capacity amount)
- Minimum 16-hour on-peak period per day

MPU Unit 9

- Minimum of 18 MW (33% of capacity amount)
- Minimum 24-hour period per day

WPS Contract Purchase

- Minimum of 50% of contract capacity for 200 hours per month during off-peak hours
- Minimum of 100% of contract capacity for all other hours
- No minimum number of hours per day when dispatched

WE Contract Purchase

- Minimum of 0% of contract capacity for both off-peak and on-peak hours
- No minimum number of hours per day when dispatched
- Minimum energy take equal to 50% load factor

RICE Resource

- No minimum output
- No minimum number of hours per day

Combined Cycle

- Minimum of 10 MW (40% of capacity amount)
- Minimum of 8 hours on peak per day

Lakeswind Wind Resource

- Scheduled based on historical hourly output

1.5.11 Resource Dispatch

For each of the 200 random draws, all generation resources that possessed scheduling flexibility were "dispatched" within the model to optimize the value of the energy delivered to MISO, within constraints reflective of the operating limitations of each resource as described above. For each hour of each year of each simulation, the hourly MISO market energy price (LMP) and marginal production cost of each resource (including variable costs and CO2 emission costs) were used to calculate the optimal output level of the resource to achieve the highest net margin (MISO sale price less production cost), bounded by the minimum and maximum dispatch limits of each resource. This optimal output level was then used to calculate the associated revenue (from the sale to MISO), production cost, and net margin for each hour for each facility.

Using these hourly net margin calculations, each facility was then committed (on/off decision) by day for each year of each simulation, subject to the operating limitations. The commitment parameters differed by facility, reflecting the differing operating limitation of each.

1.6 GLU Least Regret Model

1.6.1 Least Regret Methodology

Instead of performing selected sensitivity options for future changes in input parameters, a least regret methodology was used to evaluate the cost effectiveness of the options for future random fluctuations in input parameters.

The options described above were assessed and ranked by means of a least regret methodology. For each of the 200 simulated futures, each option is scored using its 20-year NPV of net costs (costs less MISO revenue). For each year of each simulated future, the NPV is calculated for each option using a 5% discount rate. For each option and each simulated future, the 20 annual NPV values are added together to calculate a 20-year NPV.

Within each of the 200 future simulations, the option with the lowest 20-year NPV represents the optimal choice for that future simulation. For each simulated future, the value of this minimum 20-year NPV is subtracted from the 20-year NPV values of each of the other options, resulting in a "regret" score for each option. The optimal option in each future simulation has a zero-valued regret score. This process is repeated for each of the 200 futures for each option.

The regret score for each option and for each of the 200 future simulations is then squared (to emphasize the penalty for higher-valued regret) and summed for each option for the 200 futures. The sum-of-squared-regret score for each option is then used to rank the options. This scoring provides a relative assessment of each option with respect to the other options under consideration, but has no absolute value.

The purpose of this assessment methodology is to evaluate the robustness of performance for each option across the variability represented by the simulated futures of external factors and inputs. A robust option is one that performs well in a majority of futures, though possibly not being the optimal option for any single future. The number of times an option achieved a certain rank also provides an indication of the robustness of the option for variations in future conditions.

The results for the GLU least regret analysis are summarized in the following table. Due to using the squared function as described above, the Least Regret Score is useful identifying the least-cost option, but the difference in Least Regret Scores does not provide an indication of the economic difference between options. The NPV amount is a better metric for comparing the relative difference of the options as shown in the following table.

1.6.2 Least Regret and NPV Analysis for GLU-East

The options described above for GLU-East were assessed and ranked by means of a Least Regret Score, calculated as described above, and the five most cost-effective options are summarized in the following table. For each option, the number of futures (out of 200) that had the Least Regret Score ranking shown is also listed in the table.

The following table also shows the 20-year NPV for each option and the 20-year NPV percent difference relative to the most economical option.

Table 1-15
GLU-East Estimated Cost Summary for the Five Most Cost-Effective Options

	Option 3 RICE & Solar	Option 4 Solar	Option 1 Status Quo	Option 5 Comb. Cycle	Option 8 RICE & Solar & Wind
20-Year NPV ($M) [1]	801	811	813	818	819
Amount above Solar Option ($M)	0	10	12	17	18
Percent above Solar Option	0.0%	1.3%	1.5%	2.1%	2.3%
Least Regret Score	5,070	81,252	75,254	75,304	114,160
Rank by LRS	1	3	2	4	5
Number of simulations with rank shown above [2]	200	137	137	137	197
Number of simulations with rank shown above or better [2]	200	200	137	137	200

[1] The NPV values are based on median costs for the 200 simulations.
[2] Out of a total of 200 simulations.

The above table indicates that the most cost-effective option is the RICE and Solar option with the next four options ranging from 1.3% to 2.3% more expensive based on the estimated 20-year NPV of power costs. The estimated 20-year NPV for the five options ranges from $801 million to $819 million. These estimated NPV values are based on the median values for the 200 simulations. However, the percentage differences between NPV values for the various options, taking into account all 200 simulations, is not significantly different from the percentage differences shown in the above table.

As shown in the above table, the RICE and Solar option maintained its Number 1 Least Regret Score rank for all 200 future simulations.

The following table shows the results for the next three options relative to the most economical option.

Table 1-16
GLU-East Estimated Cost Summary for the Three Least Cost-Effective Options

	Option 3 RICE & Solar	Option 6 RICE & Wind	Option 7 Solar & Wind	Option 2 Wind
20-Year NPV ($M)[1]	801	823	830	849
Amount above Solar Option ($M)	0	22	30	48
Percent above Solar Option	0.0%	2.8%	3.7%	6.0%
Least Regret Score	5,070	145,813	277,122	590,305
Rank by LRS	1	6	7	8
Number of simulations with rank shown above [2]	200	200	200	200
Number of simulations with rank shown above or better [2]	200	200	200	200

[1] The NPV values are based on median costs for the 200 simulations
[2] Out of a total of 200 simulations

The above table indicates that the next three options range from 2.8% to 6.0% more expensive than the lowest cost option based on the estimated 20-year NPV of power costs. The estimated 20-year NPV for the three options ranges from $823 million to $849 million.

1.6.3 Economic Analysis for GLU-West

The options described above for GLU-West were assessed and compared based on the estimated 20-year NPV as summarized in the following table.

Table 1-17
GLU-West Least Regret Summary

	Option 1 Status Quo	Option 2 Merge GLU-West & GLU-East
20-Year NPV ($M)	96	125
Amount above Status Quo ($M)	0	28
Percent above Status Quo Option	0.0%	22.8%

As shown in the above table, the Status Quo option is 22.8% lower than the Merge GLU-West and GLU-East option.

1.7 Regulatory Environmental Issues

Various permits and authorizations are required for operation of electric generating facilities. These permits and authorizations, including key permits authorizing air emissions and wastewater discharge, have been obtained for the MPU Unit 8 and Unit 9 generating facilities as required. Details of these permits and approvals were provided in the May 7, 2018, Long Range Planning Review report.

Currently, Manitowoc County is designated as attainment/unclassifiable for the one-hour NOx and SO_2 standards. As described in an Air Program Fact Sheet issued by the WDNR, on May 1, 2018, the USEPA notified the state of Wisconsin that it is designating an area of Manitowoc County as marginally nonattainment for the 2015 ozone standard extending approximately several miles inland from the Lake Michigan lakeshore.

MPU Units 8 and 9 are within the 2015 ozone nonattainment area and the MPU Custer CT is outside the 2015 ozone nonattainment area. Per discussions with the WDNR, MPU does not expect MPU Unit 8 and Unit 9 to be affected by the 2015 ozone nonattainment area designation. After an area is designated as ozone nonattainment, there are various requirements that could be implemented depending on the severity of the nonattainment and the plan developed for attainment by the WDNR. However, at this time it is not known what specific requirements will be implemented. Often there are Reasonably Achievable Control Technology requirements for existing sources, which are generally emission limits for NOx. The WDNR fact sheet indicates the date for attaining the 2015 ozone standard is likely to be around July 2021.

New or modified major sources of emissions in ozone nonattainment areas are subject to Nonattainment New Source Review permitting requirements. Permitting a new unit in an ozone nonattainment area would likely require offsets and Lowest Achievable Emission Rate technology for NOx, which typically would be selective catalytic reduction ("SCR").

The RICE installations considered in this study are proposed to be installed outside of the nonattainment area described above and would not be affected by the nonattainment requirements. SCR might be required even in an ozone attainment or unclassifiable area.

1.8 GLU Renewables Review

1.8.1 GLU-East Renewables Review

The renewable requirements of GLU-East are summarized below. The renewable requirements are based on a percentage of retail sales and do not increase after 2019. The supply of renewable energy is provided as a share under the WE and WPS wholesale contracts, from GLU generation (partially wood waste burning), and from the Lakeswind Project.

The following table presents the GLU-East Status Quo Option without new generation.

Table 1-18
GLU-East Forecast Renewable Requirements and Supply (MWh) for Status Quo Option

Period	Requirements	Status Quo Supply	Supply as Percent of Requirements
2019 – 2026	111,129	123,277	111%
2027 – 2029	70,137	85,611	122%
2030 – 2032	70,137	72,352	103%
2033	70,137	44,924	64%
2034	70,137	11,231	16%
2035 – 2038	70,137	0	0%

As shown above, the GLU-East renewable energy supply is expected to equal or exceed the GLU-East renewable energy requirement through the end of 2032 for the Status Quo Option. Due to the relatively low cost of renewable energy credits, the value of the renewable energy credits associated with the renewable energy options was not evaluated.

1.8.2 GLU-West Renewables Review

The renewable requirements of GLU-West are summarized below. The renewable requirements are based on a percentage of retail sales and do not increase after 2019. The supply of renewable energy is provided as a share from the Lakeswind Project.

The following table presents the GLU-West Status Quo Option without new generation.

Table 1-19
GLU-West Forecast Renewable Requirements and Supply (MWh) for Status Quo Option

Period	Requirements	Status Quo Supply	Supply as Percent of Requirements
2019 – 2033	21,837	27,528	126%
2034	21,837	6,882	32%
2035 – 2038	21,837	0	0%

As shown above, the GLU-West renewable energy supply is expected to exceed the GLU-West renewable energy requirement through the end of 2033 for the Status Quo Option.

1.9 GLU Existing Power Supply Portfolio Review

1.9.1 GLU-East Power Supply Portfolio

The GLU-East existing power supply portfolio includes the MPU CFB units and various capacity and energy purchases as described above. These resources are accurately modeled in the power supply planning analysis based on typical utility practices.

1.9.2 GLU-West Power Supply Portfolio

The GLU-West existing power supply portfolio includes various capacity and energy purchases as described above. These resources are accurately modeled in the power supply planning analysis based on typical utility practices.

1.10 Key Conclusions and Recommendations

GLU should consider the following conclusions and recommendations along with its other business, financial, economic, and regulatory considerations.

1.10.1 Conclusions

- The methodology used by GLU for the power supply planning was found to be sound and consistent with prudent power supply planning procedures
- GLU-East has a need of additional 40 MW of capacity beginning with the 2023/2024 MISO planning year and increasing to 159 MW by 2038.
- GLU-East does not need additional renewable energy resources until 2033 with the current Wisconsin renewable energy credit regulations.
- For GLU-East, the 35 MW RICE option with procurement of engine-generator sets at a discounted amount in conjunction with 15 MW of solar capacity is the option with the lowest estimated 20-year NPV and Least Regret Score.
- The RICE & Solar option, for which engine-generator sets at a discounted cost will not always be available, provides GLU-East with an opportunity to fix a portion of its capacity costs to hedge against rising MISO capacity costs as existing MISO resources are retired.
- Based on an estimated 20-year NPV analysis, the other options ranged from 1.3% ($10 million) to 6.0% ($48 million) more expensive than the RICE & Solar option
- GLU-West has estimated capacity needs of 35 MW from 2023 through the end of the Study Period.
- GLU-West has estimated energy needs of approximately 18,000 MWh per year (or about 10% of the aggregate energy requirements) through 2030 and 185,000 MWh per year (or 100% of the aggregate energy requirements) through the end of the Study Period.
- GLU-West has under contract a wind resource that is expected to meet 126% of its annual renewable energy requirements through the end of the Study Period.
- For GLU-West, the Status Quo option is 22.8% or $28 million less expensive on an estimated 20-year NPV basis than the GLU-West Merge with GLU-East option.

- The implementation of DSM reduced the 20-year NPV of all options by about 0.5%, but did not affect the relative economic results for the options.

1.10.2 Recommendations

- After the GLU Board has accepted the recommendations, a GLU project committee should be created to pursue acquisition of the 35 MW of RICE capacity for GLU-East and GLU-West members.
- A GLU project committee should be created to pursue acquisitions of distribution-connected solar resources for GLU-East and GLU-West members.
- In conjunction with the above, enter into a non-binding agreement to acquire three 11.7 MW RICE engine-generator sets available at a discounted price.
- Authorize activation of Phase 3 of the GLU Long Range Power Supply Analysis for siting the RICE resource, preparing preliminary layouts, and confirming budgetary and annual costs in this study.
- Submit a MISO generator interconnection request after the RICE resource site has been selected and confirmed.
- Prepare applications to the PSCW and WDNR.
- After approvals have been received, prepare design and procurement documents.

Appendix A

PowerPoint Presentation to GLU Board August 13, 2019